Domestic Petroleum Council

Anadarko Petroleum Corporation
Apache Corporation
BHP Petroleum (America)
Burlington Resources Oil & Gas Company
Cabot Oil & Gas Corporation
Devon Energy Corporation
Enron Oil & Gas Company
Enserch Exploration, Inc.
Kerr-McGee Corporation
The Louisiana Land & Exploration Company
Maxus Energy Corporation
Mitchell Energy Corporation
Monterey Resources, Inc.
Oryx Energy Company
Santa Fe Energy Resources, Inc.
Union Pacific Resources Company
Vastar Resources, Inc.

May 27, 1997

BY U.P.S. OVERNIGHT

Mr. David S. Guzy
Chief, Rules and Procedures Staff
Minerals Management Service
Royalty Management Program
Building 85
Denver Federal Center
Denver, CO 80225

Re: Notice of Proposed Rulemaking, 62 Fed. Reg. 3742 (January 24, 1997)

Dear Mr. Guzy:

The Domestic Petroleum Council ("DPC") welcomes this opportunity to comment on the notice of proposed rulemaking the Minerals Management Service ("MMS") has issued regarding the value of the federal royalty on oil. The DPC is a national trade association representing the nation's largest independent oil and gas producers. Collectively, its seventeen member companies produce a significant portion of all oil and gas from Federal lands. As independent producers, DPC's members see their interests aligned with those of MMS, being best served by obtaining the highest possible price at the lease for the oil and natural gas they produce.

DPC is advised that MMS may reopen the comment period on the proposed rule. If that occurs, DPC will comment separately on any matters raised in the notice of extension.

Summary

The DPC opposes the proposed valuation rule. The rule improperly seeks to give MMS a claim to royalties on the profits of companies participating in the midstream market for crude oil. It abandons without justification the Department of the Interior's historical policy of royalty parity: that the royalty consequences for non-arm's-length sales should be equal to those for comparable arm's-length sales. And it abandons the

Department's longstanding reliance on arm's-length transactions for sales of oil in the lease market as the foundation for valuing royalty.

This rule has grown out of MMS's decision to abandon reliance on posted prices as a basis for valuing royalties on a lessee's non-arm's-length sales of crude oil. MMS advises that almost 70 percent of oil produced from federal leases is not sold at arm's length. While the volume of crude oil sold under non-arm's-length arrangements may be high, the number of companies selling under these arrangements constitute a small percentage of the number of companies which will be dramatically impacted if this rule is adopted.

The agency's stated goal is to "decrease reliance on oil posted prices" as a measure of market value. 62 Fed. Reg. 3742. But the result this proposal reaches is to eliminate reliance on market prices at or near the wellhead. Wellhead prices are the best measure of market value at the wellhead: the only point MMS may lawfully determine royalty value. Most of the time, the proposed methodology will result in an overvaluation of the government's royalty share. The proposed rule is simply a new, hidden federal severance tax.

Neither the rulemaking notice nor the related documentation from the rulemaking record (which MMS has released under the Freedom of Information Act) supports the need for an amendment to the current regulations. It appears from that record that MMS has adopted a set of assumptions about oil markets from consultants whose primary business is to aid the plaintiffs' bar in conducting litigation against producers of oil and natural gas. (Indeed, at least one of these consultants originally obtained contingency fee contracts of up to 50% from his clients.) These assumptions have not been tested by any empirical study, have not been made as a result of MMS's own auditing program, and have not even been the subject of any peer-reviewed academic paper in the field of economics. They have, however, been preliminarily examined in litigation. In *Engwall v. Amerada Hess*, No. CV-95-322 (5th Jud. Dist. N. M.), the court refused to certify a class action proposed by plaintiff-lessors, based on the theory that valuation should begin with prices for oil traded in Cushing, Oklahoma, then adjusted back to leases in New Mexico. It did so because the "various claims asserted by plaintiffs ... are novel in the sense that plaintiffs have not cited to the Court previous precedent from any jurisdiction which has accepted plaintiffs' legal theories with regard to the royalty and overriding royalty obligation...." *Id.*, Decision at 2 (March 26, 1997). MMS has failed to lay the foundation for the dramatic change it seeks to impose.

If, however, the Department of the Interior determines that it will alter the current rules, DPC offers two alternatives which more rationally address the concerns identified in the rulemaking notice. The first alternative is for the Department to exercise its right on almost all federal leases to take its royalty share in kind. As owner of about 3 percent of domestic U.S. production, the Department would be, in effect, one of the largest producers of crude oil in the country. It could use its market power over its aggregated volumes of oil in an effort to obtain higher prices at downstream market centers. It could also dramatically shrink the size of the MMS's workforce. The need for auditors and legal staff to process administrative appeals would decline dramatically. The Clinton Administration could take justifiable pride in converting the agency into a lean, cost-effective enterprise promoting the public's fiscal interests. As a guidepost, the Department need only look to the royalty in kind program run by the Province of Alberta, Canada.

The second alternative is for the Department to recognize and accept the truth: there is, and has long been, a vibrant market for crude oil at the lease. The sales transactions occurring at these points offer the best evidence of the value of royalty oil at the wellhead. If it is not yet prepared fully to market its royalty share in kind, the Department should continue to define and treat arm's-length sales as it does in the current rules: the royalty value is what the lessee receives under the sales contract. For non-arm's-length sales, the Department should alter its current benchmarks. The change would eliminate any reference to posted prices. The Department would rely instead on arm's-length transactions in the same field and on its own prices received from its sales of royalty in kind in that field. For any field in which the Department determines that no arm's-length sales are occurring, the Department would be sure to take its royalty in kind there. Each quarter, for each field in which the Department is not taking its royalty in kind in full, the Department would publish information on prices received in arm's-length transactions during the prior quarter. This would allow lessees selling in those fields under non-arm's-length arrangements (or moving the oil without sales) to bring their royalty payments into line quickly. MMS would be assured of faster receipt of the correct value, and lessees would avoid MMS claims for additional royalties six years later coupled with hefty interest charges and penalties. DPC offers proposed regulatory wording to fix MMS's perceived difficulties with the current benchmark system.

AN INTERIM RULE WOULD BE BAD PUBLIC POLICY

MMS is considering adopting this proposal as "an Interim Final Rule while it further evaluates the methodology in this proposed rule." 62 Fed. Reg. 3743. The alleged benefit of an interim rule would be to give MMS "the flexibility to do a revision after the first year without a new rulemaking." *Id.*

DPC firmly opposes this idea. When this proposal was issued, MMS stated its belief that independent producers would continue to be covered by the gross proceeds approach for valuation of oil. Our conversations with MMS at the public hearings on the proposed rule revealed, however, that the proposal proved to be more sweeping than the agency realized. If MMS had not followed notice and comment procedures with the proposed rule, but in the name of "flexibility" had issued a final rule on January 24, then virtually all independent producers would now find themselves valuing oil using the NYMEX price. Now MMS wants the "flexibility" to effect still more changes a year later without any further opportunity for public comment.

DPC thinks that position is unwise. The process of public comment is not a harness. It is an opportunity for the agency to learn and for the affected constituents to know their concerns have been heard and addressed. Without that opportunity, the agency could make further mistakes, and lessees would have to take their concerns and frustrations to the Congress and the courts. In a democracy, railroading radical change is never well-received.

In the meantime, MMS would impose costly alterations in the recordkeeping systems of federal leases to come into compliance with the interim rule -- alterations which may need to be undone or further altered when the agency changes its mind a year later, and perhaps altered again after litigation. Even without an interim rule, it is apparent that MMS has significantly underestimated the compliance costs of its proposed scheme. DPC asks MMS to consider the preliminary analysis of these costs which DPC and other associations submitted to the Office of Management and Budget on March 25, 1997. (See exhibit 1.) If MMS proceeds with an interim rule, it will only exacerbate that underestimate.

Ultimately, an interim rule would be the <u>most</u> inefficient option. MMS must follow notice and comment procedures when adopting or amending a rule. 30 U.S.C. § 1751(b). It is most unlikely that MMS could demonstrate that it had "good cause" to adopt revisions to the interim rule without following those procedures. *See* 5 U.S.C. § 553(b)(B); *Tennessee Gas Pipeline Co. v. FERC*, 969 F.2d 1141 (D.C. Cir. 1992). A successful lawsuit would create a third set of changes in lessees' data systems, after the court throws out the agency's revision.

DPC members see a special irony in the haste with which MMS prepared this proposed rule and the agency's desire to dispense with further rulemaking before making adjustments later. This conduct is in stark contrast with the very deliberate pace MMS has adopted to review expanding its royalty-in-kind program and the three years of studied review it gave to the negotiated rulemaking for natural gas valuation. DPC was therefore pleased to learn that the agency may reopen the comment period for consideration of other options. That would be an appropriate response to the extensive comments and concerns raised by producers.

<u>MMS Should Not Abandon Royalty Parity</u>

As Assistant Secretary Armstrong promised DPC at Senator Breaux's April 9, 1997, meeting on oil valuation, MMS officials responded to DPC's question on why MMS believed its current regulations were inadequate. At the Houston hearing on the proposed rule, Deputy Associate Director Donald Sant and Division Chief Debbie Tschudy stated that the results of MMS's own auditing program demonstrate the weaknesses of the current valuation system. Their opinion is based on their view that lessees are not attempting to document that their posted prices are in line with arm's-length transactions in the field involving significant quantities of crude oil. (Transcript of April 17, 1997, public hearing in Houston, Texas, pp. 46-47.) This opinion overlooks a fundamental point. MMS has not carried out its own duty, identified by the Interior Board of Land Appeals eight years ago, to make information from its own extensive data base about comparable arm's-length sales available for use under the benchmarks. *Mobil Oil Corp.*, 112 IBLA 56, 63-64 n.8 (1989), observed that "a lessee might run afoul of price-fixing restrictions if it attempted to assemble this data. On the other hand, MMS, which receives contract information from all Federal lessees, is in a much stronger position to assert ... a determination as to whether a particular contract price is permissible."

It is not difficult to fix the current regulations to deal with the perceived problem of allowing companies who post prices to rely on their own price postings to value non-arm's-length sales. What is difficult is understanding why MMS is proposing to throw the royalty-parity baby out with the posted-price bathwater. Instead of limiting the proposed rule to the problem of posted prices, MMS is proposing

- to create a new duty to market at no cost to the federal government;
- to require companies selling to affiliates to pay royalties using either a NYMEX-based netback scheme or the affiliate's resale price; and
- to eliminate transportation allowances based on an affiliate's FERC-approved pipeline tariff.

The primary effect of these changes is to put lessees selling or transporting crude oil under a contract with an affiliate at a competitive disadvantage to those selling or transporting at arm's length. Since many independent producers, including DPC members, now have affiliates active in the midstream market for crude oil, DPC finds MMS's proposals as unacceptable as they are unauthorized.

MMS WRONGLY ASSUMES THAT LESSEES HAVE A DUTY TO BEAR ALL MARKETING EXPENSES AT NO COST TO THE LESSOR

MMS proposes to adopt a revised section 206.102(e). That subsection would state that a lessee has a duty to place production in marketable condition, 62 Fed. Reg. 3753, meaning that the oil is "sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area." 62 Fed. Reg. 3752. To this, however, MMS proposes to add a duty that the lessee must "market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government." *Id.* at 3753.

DPC objects to this "duty to market." Although we have numerous reasons for this objections, the easiest to grasp is plain from the very language of the proposal. MMS calls this a duty to market for the **mutual** benefit of the lessee and lessor, yet it states it will not share mutually in the costs. It is, in short, a duty to market for the special benefit of the lessor and to the detriment of the lessee. There is no logic behind such a duty.

Nor is the law behind such a duty. For federal leases, no duty to market without cost to the lessor can be implied, because the reason behind the implication of duties in an oil and gas lease is not present. The typical oil and gas lease is "silent about the obligation of the lessee with respect to the conduct of operations after oil or gas is first discovered." 5 H. Williams and C. Meyers, OIL AND GAS LAW § 801 (1985) (hereafter "OIL AND GAS LAW").

> The subject was, therefore, rationally left to the implication, necessarily arising in the absence of express stipulation, that further prosecution of the work [of development and production] should be along such lines as would be reasonably calculated to effectuate the controlling intention of the parties as manifested in the lease, which was to make the extraction of oil and gas from the premises of mutual advantage and profit.

Brewster v. Lanyon Zinc Co., 140 F. 801, 811 (8th Cir. 1905). The customary logic behind an implied duty to market is that without marketing of the production, there will be no production or revenue on which the lessor can claim royalty; and the promise of royalties "was the controlling inducement to the grant" of the lease. *Id.* at 809.

But MMS's quarrel here is not with a lessee's unwillingness to produce oil from a lease. It is instead with the value at which the lessee will pay royalties on oil it produces. And concerning the value of royalties, there is no room left between the lines of the leases and regulations for an implied duty to dwell. The Department has at all times had the option of taking the oil in kind and marketing it, and has routinely done so. For most leases, it also has held the power, after notice and hearing, prospectively to set reasonable minimum values for the royalty on production. It has determined through regulations what the value of royalty would be and incorporated those regulations into the text of the lease forms it drafted. Therefore, it cannot be said that the parties to these leases intended the question of how marketing production is to affect the value of royalty to be governed by an implied generalized standard of reasonableness.

Furthermore, the Department's right and ability to take oil in kind are sufficient in themselves to prevent the creation of an implied duty to market. "If the lessor's share of the oil, under the royalty provisions of the lease, is deliverable in kind to the lessor, the oil is theoretically under the control of the lessor and arguably he should be the one to market it, not the lessee." OIL AND GAS LAW § 853. The Department cannot imply a duty to serve the same purpose and achieve the same result as a duty already expressed. The lease expressly creates a duty in the lessee to provide the royalty on oil in kind, and MMS may market that share to its maximum advantage. The lessee, of course, is not responsible for MMS's costs of marketing in that setting. So the lease cannot contain an implied promise for the lessee to pay those costs when the Secretary takes his royalty share in value.

As MMS knows, there is also no express duty to market without cost to the lessor in federal leases. Nor has such a duty been incorporated into leases by regulations in existence when the leases were issued. The first rule remotely to address the subject of marketing was issued in 1936 to govern onshore leases. 1 Fed. Reg. 1996, 1999 (1936). In relevant part it stated that the "production of oil and gas ... shall be limited by the market demand for gas or by the market demand for oil." 30 C.F.R. § 221.27 (1938). In other words, the Department expressly imposed on lessees a duty not to market in order to prop up prices.

In 1942, section 221.27 was amended and redesignated as 30 C.F.R. § 221.35. 7 Fed. Reg. 4132 (1942). As amended, the rule required lessees to adopt one of three alternatives to "avoid physical waste of gas": the lessee could "consume it beneficially...," could "return it to the productive formation...," or could "market it...." 30 C.F.R. § 221.35 (1943). The obligation to market natural gas did not state that it was without cost to the lessor. Additionally, the rule continued the duty not to market from the 1936 rule. The duty not to market remained in force until repealed in 1982. 47 Fed. Reg. 47758 (1982) (amending § 221.35 and redesignating as § 221.102). The duty to market (as one option to prevent waste) remained in force, 48 Fed. Reg. 35639 (1983) (redesignating it as § 206.100), until repealed in 1987. 52 Fed. Reg. 3796, 3798 (1987) (amending § 206.100).

OCS leases never were subject to an express duty to market. For leases issued in 1956 and later, they were subject only to an express duty to "put into marketable condition, if commercially feasible, all products from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of cost of treatment." 30 C.F.R. § 250.41(b) (1956).

In sum, onshore federal leases issued between 1942 and 1987 are subject to a duty to market as one option to prevent waste of gas. Other federal leases are subject only to a duty to place oil in marketable condition. No federal lease is subject to an express duty to market oil, let alone to market it without cost to the lessor. DPC realizes that MMS's position is that the law is "well settled that marketing expenses necessary to market production from a Federal lease must be performed at no cost to the lessor." *Amoco Production Co.*, MMS-92-0552-OCS at 4 (1996) (citing *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961)). As we have just shown, that position is patently false with respect to crude oil. But even as to natural gas the precedents indicate that the more principled view is more favorable to lessees.

California Co. concerned a federal lease in Louisiana's Romere Pass field. Calco sold natural gas at a point within the field to a pipeline for 12 cents per mcf, after Calco had removed excess water vapor and compressed the gas to a specified minimum. For royalty purposes, Calco wished to deduct 5 cents per mcf from the 12 cents received to reflect its costs of dehydrating and compressing the gas. The Secretary disagreed, arguing that Calco was obliged to bear that expense alone. To the court the question concerned the meaning of the statutory phrase "value of production."

> Does it mean the raw product as it comes from the well, no matter what its condition? Or does it mean that product readied for the market in and to which it is being sold?

296 F.2d at 387. The court observed that the lessee had an express duty under BLM's rules to "market" natural gas in order to avoid the "physical waste" of the production. Specifically, BLM required the lessee "to prevent the waste of oil or gas and to avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to the productive formation." 30 C.F.R. § 221.35 (1959). Part of that duty to market the gas included the duty to put the gas in a condition acceptable to the "market, an established demand for an identified product." 296 F.2d at 388. "The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content." *Id.* While the court took care to explain that this case involved neither transportation nor manufacturing costs, *id.* at 387, *California Co.* firmly established the principle that a lessee subject to the terms of former section 221.35 had the duty to place natural gas in marketable condition.

Yet there is no bridge from that rather modest proposition to the proposed duty to market contained in the January 24 notice. The preamble to the proposal relies on *Walter Oil and Gas Corp.*, 111 IBLA 260 (1989), for its duty to market language. 62 Fed. Reg. 3746. There the lessee sought a deduction for the fee it paid an independent marketer to locate buyers, negotiate contracts, and monitor sales of gas produced from an OCS lease. IBLA upheld MMS's position, reasoning that Walter's purchasers were "willing to pay the contract price for the gas, and this price included the fees Walter paid to Commet [the marketer] for its services." 111 IBLA at 264. So, under the gross proceeds rule, IBLA found the fees for Commet's services to part of the total consideration accruing to Walter.

> The only allowances recognized as proper deductions in determining royalty value are transportation allowances for the cost of transporting production from the leasehold to the first available market.... A lessee may choose to employ its own personnel to find markets for its gas, or it may decide to hire an independent marketer to perform these functions. The lessee's business decision as to which method it prefers does not affect the value of the gas for royalty purposes.

Id.

MMS reads too much into cases such as *Walter*. If the "duty to market" requires the lessee to bear at its sole expense all costs of marketing to sell oil in an established market, then the duty would also require a lessee to bear alone the expense of moving the production to an established market. In other words, if *California Co.* really were the basis of a general duty to market in the manner proposed, there is no principled basis to distinguish transportation from any other act needed to sell the oil. Yet the

Department has conceded at least since *Shell Oil Co.*, 70 I.D. 393 (1963), that transportation costs need to be deducted from the proceeds of sale.

IBLA has attempted to explain the distinction, and its explanation undercuts the proposed rule. In *ARCO Oil & Gas Co.*, 112 IBLA 8 (1989), IBLA rejected the analogy between deductions for transportation and those for other marketing expenses.

> The analogy sought to be drawn ... is unpersuasive, because it fails to draw upon similar circumstances. . . . But for the fact that the only market was onshore at a point distant from the lease, the transportation costs ... would not have been incurred by the lessee. . . . No allowance will be recognized by the Department where a lessee, as here, would have borne similar costs attributable to the creation and development of markets regardless whether production was sold on or adjacent to the lease.

Id. at 10-11. In sum, even if a duty to market based on *California Co.* applied to oil, it would require a lessee to bear at its sole expense only those costs that it would otherwise have incurred if it had sold the production at the lease. Beyond that, the lessor is not entitled to claim royalties on the value added to crude oil by those expenses and risks unique to downstream activities.

MMS's assertion of a duty to market has already led to overreaching claims for royalties. Most often the claims come in the context of a producer which sells production to an affiliated company or which transports it through an affiliated pipeline. But MMS has even extended the theory to transactions between a small, independent producer and a completely unaffiliated purchaser.

In *Amerac Energy Corp.*, MMS-93-0868-OCS (1996), *appeal pending*, Amerac sold its OCS crude oil at the lease to Essex Refining Company at monthly average posting of a third party for Louisiana Light Sweet crude oil. Amerac then entered a separate arrangement under which Essex would give it 50% of the net profits Essex generated from downstream marketing activities, including term sales with refineries, spot sales, trading and hedging activities on the NYMEX, and crude oil processing. Amerac paid royalties on its share of the net profits. But the Director ruled that Amerac also owed royalties on Essex's share of the net profits because Amerac was simply paying Essex to market the oil. On the contrary, it appears that Amerac had simply negotiated a form of bonus, but one under which Essex faced less risk than if it had paid an outright premium over posting. DPC's point here is not on the merits of Amerac's appeal, but is instead that if MMS is willing to use the alleged duty to market to attack arm's-length transactions involving profits in the midstream market, it will apply it all the more eagerly to transactions between affiliates in the midstream market.

Until recently, it was the Department's policy to treat transactions between affiliates in a manner leaving them in royalty parity with unaffiliated transactions. Now, however, MMS views transactions between affiliates as attempts to evade royalty obligations. One reason DPC supports the expansion of royalty in kind is that it would give the agency a sobering education in the marketplace on the role played by companies acting in the midstream of commerce -- between the wellhead on one end and the market center or refinery on the other.

Midstream companies are typified by independent marketers such as Scurlock Permian Corporation, which testified at the April 17 hearing in Houston. Scurlock competes with other marketers and with refiners to purchase crude oil in the field. It moves the oil through trucks, gathering lines, and pipelines to market centers. It maintains an inventory of stored crude oil at various locations around the country. That inventory enables it to enter exchanges, which often are more efficient means of "repositioning" crude oil than actual transportation of it would be. This aggregation of oil in inventories does not just permit more efficient movement of oil from a given lease to its ultimate destination, it also helps create a market for low-volume wells, such as stripper wells. Most refiners have no interest, because of high transaction costs, in seeking out producers who can offer less than 10 barrels per day from a well. To a refiner, the value of such oil may be several dollars a barrel less than it would pay for oil of similar quality from a more prolific field. Marketers like Scurlock aggregate these small volumes into "packages" of a size that will attract more competitive purchasing.

Midstream companies perform a variety of services and bear a variety of risks once the oil moves beyond the lease meter.

- Transportation
  - Contracting for or Providing Transportation
  - Scheduling of Volumes
  - Providing Pipeline Fill
  - Tracking Volumes Delivered
  - Providing Credit Services

- Storage
  - Constructing or Leasing Storage Facilities
  - Scheduling Storage Volumes
  - Maintaining Inventory

- Risk Management
  - Dealing with Price Fluctuations at or Upstream of Market Centers
  - Risk of Loss of Pipeline Volumes
  - Environmental Liabilities for Spills
  - Risk of Purchasers' Default

- Marketing
    - Aggregating Volumes
    - Satisfying Specialized Customer Quality Preferences

These services and risks undertaken add value to the oil beyond its value at the wellhead. These are risks the Department currently undertakes when it takes its royalty in kind. The Department manages these risks by assigning them to the refiner under the royalty-in-kind sales contract, which is why the Department only receives the wellhead value when it sells the oil, but it undertakes these risks nonetheless. The new duty to market is simply MMS's effort to unilaterally compel lessees to assume these risks beyond the lease market when MMS takes its royalty in value. As IBLA has held in a similar context, it "would be an anomalous result if the Government royalty interest was, in effect, chargeable with transportation when taken in kind, but not when taken in value." *Kerr-McGee Corp.*, 22 IBLA 124, 128 (1975). So, too, MMS cannot refuse to charge the federal royalty interest with the risks and costs of the midstream market when taking royalty in value, when it must accept those risks when taking royalty in kind.

The result cannot be different simply because a producer creates an affiliate to participate in the midstream market. Those affiliates compete with independent marketers like Scurlock to provide the same midstream services, expend the same costs, and assume the same risks. They add value to the wellhead value in precisely the same way. No law or Departmental policy forbids a producer from entering into another legitimate line of business. The wellhead value of oil from a given well cannot be different simply because it is purchased by an affiliate instead of an independent marketer.

<u>FERC APPROVED TARIFFS AS TRANSPORTATION ALLOWANCES</u>

In the past, the Department believed that the value of production at the lease was determined by the marketplace and that the value at the lease was not different simply because the production was transported by a pipeline affiliated with the producer. *Shell Western E & P Inc.*, 112 IBLA 394 (1990); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164 (1990). The 1988 valuation rules generally continued that belief; and while MMS's enforcement positions under the 1988 rules have deviated from this principle, at least one court has held that the rules still permit equal treatment for transactions with affiliates. *See Mobil Exploration & Producing U.S., Inc. v. Babbitt*, 913 F. Supp. 5, 11 (D.D.C. 1995) (in reviewing whether MEPUS's transportation allowance for the Cortez Pipeline tariff complies with 30 C.F.R. § 206.157, "the agency may simply decide that, in this circumstance, a non-arm's-length arrangement must be treated in the same manner as an identical arm's-length arrangement").

One way in which the 1988 rules continued royalty parity in transportation allowances is to allow an affiliated producer to deduct the full tariff it pays to a pipeline if that pipeline operates under a FERC-approved tariff. 30 C.F.R. § 206.105(b)(5). However, proposed § 206.105, 62 Fed. Reg. 3754, would prevent lessees from relying on FERC approved tariffs whenever they ship oil through a pipeline in which it owns a sufficient interest for it to be deemed in "control" of the pipeline. The rationale for the change is that "FERC ruled that it lacks jurisdiction to enforce the Interstate Commerce Act with respect to oil pipelines located wholly on the [OCS]. See *Oxy Pipeline, Inc.*, 61 FERC ¶ 61,051 (1992) and Bonito Pipe Line Company, 61 FERC ¶ 61,050 (1992)." 62 Fed. Reg. 3746. On the contrary, FERC has not renounced jurisdiction over all oil pipelines transporting on the OCS, but simply applied existing precedents to Oxy's specific facts.

Since the beginning of this century, the law of the United States has been that the transportation of crude oil by pipeline, whether onshore or offshore, is subject to the Interstate Commerce Act ("ICA") if it is part of a chain of transportation that, viewed in its entirety, is interstate in nature. Thus, the ICA imposes jurisdiction over the transportation of crude oil by pipelines in certain situations and the determining factor is not whether such transportation is offshore or onshore, but whether or not it is in interstate commerce. The courts and FERC have also held that in determining the essential character of commerce, the most important factor is the transportation intent of the shipper at the time of shipment.

In support of its argument that its transportation was not jurisdictional, Oxy Pipeline averred that "its pipelines cross no state lines, that it 'has no knowledge of the ultimate destination of the oil,' and that no non-owner of the pipelines has ever expressed an interest in shipping oil over the pipelines." *Oxy*, 61 FERC at 61,226 - 61,227. Applying the standards established by the U.S. Supreme Court, it is obvious that the "transportation intent of the shipper" was to transport oil from one point to another on the OCS with no knowledge of the ultimate destination and therefore no intent for the transportation to be a link in a chain of transportation in interstate commerce. The FERC thus determined that based on the facts presented, Oxy's transportation was "solely" on or across the OCS, not in interstate commerce and, therefore, not subject to the jurisdiction of the ICA.

It is essential to recognize, however, that the FERC also held that the transportation would be subject to ICA jurisdiction if "the facilities [the chain of transportation] exited the OCS and the oil moved in interstate commerce." *Id.* at 61,227. (bracketed comment added). Moreover, a footnote to the opinion stated that:

> A pipeline that starts on the outer Continental Shelf and transports oil through the seaward boundaries of the States to shore for further movement, in interstate commerce is jurisdictional under the ICA.

Id. at 61,228, footnote 14. This position, which is essentially a restatement of the law as interpreted by the Supreme Court, was restated by FERC Chair Mohler in a letter to the Acting Director of the MMS ("Mohler Letter"), a copy of which is already in your files. Chair Mohler provided the following example:

> if a shipment commenced offshore, moved through Pipeline A to a point in a state adjacent to the OCS, and then moved through Pipeline B to a point in another state,... the intent of the shipper to ship in interstate commerce to the point in the other state would show that the movements through Pipeline A and Pipeline B were merely links in an interstate chain of movements that would be subject to jurisdiction under the ICA. Thus, in making a jurisdictional determination, the essential character of the movement across state lines would be determinative that the movements through Pipeline A and Pipeline B were in interstate commerce,...

Mohler Letter at 1-2. In this example, although there is transportation of oil on or across the OCS, such transportation is subject to the jurisdiction of the ICA and the FERC because it is not "solely" on or across the OCS, but is a link in an interstate chain of movements that happens to include transportation on the OCS.

The FERC has not renounced jurisdiction over transportation of oil on the OCS, but has made it clear that the only oil transportation on the OCS that it has ever exercised jurisdiction over was transportation in interstate commerce. In her letter to the Acting Director of MMS, Chair Mohler states that "there are no instances where the Commission has asserted jurisdiction over a pipeline transporting oil solely on or across the OCS." Mohler Letter at 2 (emphasis added). Since the Commission frequently exercises jurisdiction over pipelines transporting oil on the OCS, this statement can only be interpreted as further confirmation that those pipelines over which the FERC has exercised ICA jurisdiction are transporting oil on the OCS as part of an interstate chain of transportation.

On January 18, 1997, the Director, MMS, rejected the view that FERC had disclaimed all jurisdiction over OCS pipelines. *Torch Operating Co.*, MMS-94-0655-OCS at 5 (1997). Therefore, the proposal to eliminate reliance on FERC tariffs is inconsistent with MMS's precedent.

Although MMS's proposed change is unsound policy, the status quo is not acceptable either. MMS's efforts under the 1988 rules to deny affiliated producers the use of comparable arm's-length transportation costs has made it more expensive for those producers to operate and has created inequities. Accordingly, DPC petitions the Secretary of the Interior to amend the current provision permitting the use of a FERC-approved tariff to reestablish the Department's longstanding principle that the value of non-arm's-length transportation arrangements will be, for royalty purposes, the same as the value of comparable arm's-length arrangements.

MMS's current "cost-of-service" approach to non-arm's-length transportation allowances is a vestige of the days when the government believed that price controls on crude oil could be rationally and efficiently administered. The nation learned from hard experience and petroleum shortages the error of that view. FERC has moved away from cost-of-service principles toward market rates in regulating pipeline transportation. Reed & Michalopoulos, *Oil Pipeline Regulatory Reform: Still in the Labyrinth?* 16 ENERGY LAW J. 65, 74-93 (1995). The Federal Gas Valuation Negotiated Rulemaking Committee took a significant step away from the cost-of-service approach, proposing that the transportation allowance on a non-FERC pipeline would be based on third-party contracts if more than 30% of the gas is moving on that line under arm's-length contracts. FINAL REPORT: FEDERAL GAS VALUATION NEGOTIATED RULEMAKING COMMITTEE 24 (MARCH 1995). It is certainly time for MMS to go back to the practice of following market-based rates in valuing the transportation allowance.

Therefore, pursuant to 43 C.F.R. Part 14, DPC petitions that current section 206.105(b)(5) be redesignated as section 206.105(b)(5)(i), and that a new subparagraph (ii) be added to that paragraph:

> (ii) Notwithstanding any other provision of subsection (b), the transportation allowance granted under subsection (b) shall never be less than the allowance granted for a comparable arm's-length transportation arrangement.

<u>ROYALTY VALUE CANNOT BE BASED ON RESALE PRICES</u>

MMS proposes to give lessees who sell oil to affiliates an option for valuation for the first two years under the proposed rule: either to use the NYMEX-based price or to to use the price received by its affiliate when reselling the oil downstream. 62 Fed. Reg. 3742. This second option would not be available if the lessee purchases oil from third parties. *Id.* As we will explain below, because DPC members routinely purchase crude oil for a variety of reasons, this second option would not be available. But because the concept of using an affiliate's resale price reflects a misunderstanding of the crude oil marketplace, a brief comment is warranted.

It has recently become the MMS's position that a downstream resale price may be used to value oil or gas at the lease. *See, e.g., Xeno, Inc.*, 134 IBLA 172 (1995), *appeal pending*. But, as DPC has demonstrated on pages 5-11 above, a resale of crude oil in the midstream market is not comparable to a sale at the lease, because of the significant additional risks and expenses the midstream marketer assumes. Therefore, even if MMS were to abandon its proposed restriction on the purchase of crude oil to make resale prices a possible basis for valuation, the use of resale prices is conceptually unsound. It simply reflects the agency's desire to claim a risk-free royalty on the profits, if any, from transactions in the midstream market.

Instead, the Department should return to its historical reliance on comparable arm's-length sales in the lease market. And on that point, MMS's proposal is based on a host of misconceptions.

MMS'S ASSUMPTIONS IN THE PROPOSED RULE; DPC'S CRITIQUE

MMS's proposed rule is premised on fundamentally false assumptions about crude oil markets. Although these assumptions are interrelated, it is necessary to separate them to allow for adequate discussion.

1. MMS Wrongly Assumes There Is No Longer a Market for Crude Oil At or Near the Wellhead Which Can Be Used Reliably for Valuing Federal Royalty.

MMS's proposal pays lip service to the concept of valuing production using information from the wellhead market, because it acknowledges "the presence of true arm's-length sales, especially by independent producers with no reciprocal purchases or trades...." 62 Fed. Reg. 3744. As to these sales, MMS says it will continue to accept the lessee's gross proceeds under the sales contract as the correct value for royalty purposes. Proposed 30 C.F.R. § 206.102(a).[1]

But MMS's proposal also asserts that most initial transactions are suspect, 62 Fed. Reg. 3744, suggesting the belief that the thousands of independent producers selling crude oil in this country have created a collusive market. This, of course, is the same market in which the MMS itself participates as a seller of crude oil from the wellhead. MMS takes about one-third of its royalty on oil in kind and sells the oil itself. The prices it has received are the same prices which producers have received. MMS's words are not consistent with its deeds.

The proposed rule is so unmoored from the Department's longstanding approach to valuation that it is essential for MMS to recall what those moorings are. The Department of the Interior issues and administers oil and gas leases under the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331 *et seq.*, the Mineral Leasing Act, 30 U.S.C. §§ 181 *et seq.*, and the Acquired Lands Leasing Act, 30 U.S.C. §§ 351 *et seq.* For the purpose of this rulemaking, the Department's authority under each is essentially the same. The Secretary is to issue leases while reserving a royalty of a given percentage of the amount or value of oil produced and removed or sold from the lease.

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[1] This statement is qualified by five exceptions, listed in proposed section 206.102(a)(2) through (6). As we will discuss below, three of these exceptions completely swallow the rule, wrongly placing all federal lessees into the NYMEX/ANS valuation scheme. For now it is enough to note that MMS -- at least in theory -- has not completely abandoned its historic reliance on valuation in the wellhead market.

For royalty purposes, value "means 'reasonable market value'; that price which a product will bring in an open market, between a willing seller and a willing buyer." *United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. Cal. 1947), *aff'd sub nom. Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950). *See also California Co. v. Udall*, 296 U.S. 384, 387 (D.C. Cir. 1961) ("value" under Mineral Leasing Act means "fair market value"). *Cf. NRDC v. Hodel*, 865 F.2d 288, 312 (D.C. Cir. 1988) (approving Secretary's "willing buyer and willing seller" test for fair market value in the sale of leases); *Amoco Production Co. v. Hodel*, 877 F.2d 1243, 1245 (5th Cir. 1989), *cert. denied*, 493 U.S. 1002 (1989) (applying this fair market value test to oil and gas royalties).

Under the leasing statutes, it has long been settled that volumes of production are measured and valued at the wellhead on the lease. *General Petroleum Corp.*, 73 F. Supp. at 254 ("royalties are payable on the gas as it is produced at the well"); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164, 171 (1990) ("normally gas is sold and valued for royalty purposes at the wellhead"). Even the Department's most attenuated method of valuing royalty, which values certain natural gas from Alaska's Kenai Peninsula by starting with the first sale's price in Japan and netting out the costs of transportation and liquefaction, is nothing more than an attempt in a "special, unique situation" to "arrive at a reasonable wellhead value." *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1385 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987). This measurement and valuation historically has occurred at the "point of royalty computation" located ordinarily "at the wellhead" or within the "lease ... boundary." (Conservation Division Manual, Part 647, chapter 1, p. 3.) Though the point is now denominated the "point of royalty settlement," 30 C.F.R. § 206.103(a)(1), its location remains unchanged. 43 C.F.R. § 3162.7-2 (onshore) and 30 C.F.R. § 250.180 (offshore).

Of course, it is not always possible for the producer to sell production at the wellhead. Whenever that situation arises, the Department values the royalty share by looking to the first sale of the production, then granting a reduction from that price for the cost of transporting it from the wellhead to the point of sale. That transportation allowance recognizes -- albeit imperfectly -- that the movement of the oil has added value to it. *Xeno, Inc.*, 134 IBLA 172, 180 (1995). But the Department's willingness to grant transportation allowances cannot obscure the fact that the Department has looked to the market nearest the lease as the proper place to begin royalty valuation. Although the Department grants transportation allowances "where there is no market in the field," *id.*, "transportation costs have been disallowed where the costs claimed were for transportation beyond the point of the nearest potential market." *ARCO Oil and Gas Co.*, 109 IBLA 34, 38 (1989). *Superior Oil Co.,* 12 IBLA 212 (1973), is the best known illustration of the principle. There the lessee sought an allowance to transport oil beyond the point of the first potential market, Burns Terminal in Louisiana. The Department denied an allowance transportation costs incurred beyond Burns. *See also Kerr-McGee Corp.*, 22 IBLA 124, 127-28 (1975) (approving allowance because lessee sought an allowance for transportation only to "the point of the first market," distinguishing *Superior Oil*). *Walter Oil and Gas Corp.*, 111 IBLA 260, 265 (1989) (transportation is deductible only "from the leasehold to the first available market"). In sum, the Department has found in the past that the market nearest the wellhead provides the best information about the value of oil at the wellhead.[2]

Accordingly, until now, MMS has looked to prices received at the wellhead or in the field. Prior to the 1988 oil value rules, the agency looked to prices paid "in the field" and to "posted prices," which under industry practice were listings of prices buyers were offering to purchase crude oil at locations in the fields specified in the posting. 30 C.F.R. § 206.103 (1987). The 1988 rules, while more specific, reaffirm the policy of accepting the lessee's proceeds under arm's-length sales agreements, 30 C.F.R. § 206.102(b)(1)(I); and when the sales were not at arm's length, the lessee in almost all cases is to look to contemporaneous posted prices or oil sales contract prices used in arm's-length transactions in the same field. 30 C.F.R. § 206.102(c).

That is certainly the approach Congress intended. The policy of Congress has been to create a federal lease consistent with "the terms of leases which have been developed and are in general use in the industry after a long period of trial and error...." H.R. Rep. No. 2078, 81st Cong., 2d Sess. 9-10 (1950) (OCS Lands Act). *See Amoco Production Co. v. Andrus*, 527 F. Supp. 790 (E.D. La. 1981) (rejecting agency interpretation of leasing statute as inconsistent with longstanding industry and agency practice); *Marathon Oil Co. v. Andrus*, 452 F. Supp. 548 (D. Wyo. 1978) (same for onshore leases). All states of which we are aware value royalty at the wellhead or on the lease. *See, e.g., Heritage Resources, Inc. v. Nationsbank*, 939 S.W.2d 118, 122 (Tex. 1996); *Babin v. First Energy Corp.*, 1997 WL 155022 (La. App. 1997); *Piney Woods Country Life School v. Shell Oil Co.*, 539 F. supp. 957, 971 (S.D. Miss. 1982), *aff'd in relevant part*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); *Hurinenko v. Chevron U.S.A., Inc.*, 69 F.3d 283 (8th Cir. 1995) (applying North Dakota law); *Vedder Petroleum Corp. Ltd. v. Lambert Lands Co.*, 50 Cal. App.2d 102, 122 P.2d 600 (1942). Consistent with this approach, Congress expressly limited MMS's power to compel royalty recordkeeping to information through the later of "the point of first sale or point of royalty computation...." 30 U.S.C. § 1713(a).

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[2] *Marathon* involved the unique situation where natural gas was not sold until after the lessee had liquefied it and shipped it by tanker to Japan. The point of first sale was in Tokyo. MMS declined to accept comparable values for gas sold in the field in Alaska's Kenai Peninsula because those prices did not reflect the "gross proceeds" the lessee actually received from its first sale. In *Xeno* MMS rejected wellhead values because it claimed that a lessee's sales to its affiliate are not really sales at all, again relying on a new interpretation of the gross proceeds principle. Neither line of analysis in these cases provides the basis for the NYMEX scheme in this proposed rulemaking. MMS is not trying simply to determine the gross proceeds of a particular lessee's "true" first sale. It rejects essentially all first sale values as "suspect," 62 Fed. Reg. 3744, and instead imputes wellhead values by starting with the price of oil traded at Cushing, Oklahoma, or "markets centers' in California, and makes a series of adjustments back to the wellhead.

What has changed in the marketplace since 1988? There are more producing wells. A greater percentage of production from federal leases is owned by independent producers, especially from OCS leases. In 1996, the federal leases produced the greatest volume of oil in any of the last nine years, over 550 million barrels; and federal production as a percentage of national production reached its highest level for the period. (Exhibit 1, p. 4.) With more wells, more barrels, and more producers than before, is MMS seriously suggesting that there is no longer a viable wellhead market?

In fact, the current wellhead market for federal lease oil is thriving. MMS knows this firsthand, for it sells its royalty oil at or near the lease, not at Cushing, Empire, or St. James. But the same is true of oil sold by lessees. DPC asked its members to estimate what percent of their sales are at arm's length in the wellhead market. (By "wellhead market" we mean any first point of sale upstream of a market center, as MMS's proposal understands the market center concept.) Responses were in the 80 to 100 percent range. Smaller independents would likely fall in the high end of this range, the vast majority selling all their production at arm's length. Even the major integrated companies which presumably refine most of the oil they produce will have arm's length sales, including sales to small independent refiners under the 20 percent set-aside clause of OCS leases issued since 1978. *See* 43 U.S.C. § 1337(b)(7).

The rulemaking record MMS has assembled so far offers further proof of a flourishing wellhead market. Dr. Mike Harris of the Reed Consulting Group advised MMS that "[t]raditionally a large portion of sales are made at posted prices" (Exhibit 2, p. 7), indicating that the sales were in the field to which the posting applied. Another unidentified presentation stated that the "first point of sale for most domestic crude is at the lease," and that a "significant portion of activity is between [third] parties...." (Exhibit 3.) Sales at the lease are generally made under longer-term commitments, in contrast with sales at marketing centers where spot sales predominate to meet the short-term changes in the needs of refiners. *Id.* Even the presentation by Micronomics, Inc., one of the consultants supporting plaintiffs' attorneys in suits against producers, did not claim that information from the wellhead market was unreliable. It simply argued that the value of crude oil at the lease can also be determined in a different way, by using the method MMS adopted in the proposed rule. (Exhibit 4.) And the presentation by Summit Resource Management, Inc., another plaintiffs' consultant, explained that "independents commonly sell outright" and conceded that the proper value for "outright" arm's-length sales should continue to be the lessee's gross proceeds. (Exhibit 5.)

Implicit in MMS's view, however, is the assumption that most oil is first sold at arm's length in spot market transactions at market centers. But crude oil market centers are not locations where producers take most of their oil for first sale. Instead, these market centers are predominantly spot markets for incremental barrels of oil not committed under term contracts for oil produced and sold at the lease level. Market centers are balancing points where month-to-month shortages and overages are balanced out. Daily assessments of oil prices, such as Platt's, reflect the spot market value for a very small portion of the crude supply purchased on any given day.

In sum, nothing supports MMS's proposed abandonment of values received from transactions at the wellhead or lease. All that MMS's documents reflect is that the further downstream one moves the crude oil, the more valuable that oil ordinarily becomes. But the higher price that the oil may receive reflects higher risks that persons take when they move oil away from the lease and closer to market centers and refineries. These include risk of loss, risk of environmental liability, and risk of unfavorable price changes. The higher price typically also reflects the greater benefit one receives when aggregating large volumes of oil from many smaller wellhead streams. And the higher price reflects the additional cost incurred to move oil from the lease, to store it, to blend it, and to account for it once it is commingled with oil from other sources.

The difference between spot sales prices at market centers and longer-term sales prices at the wellhead is hardly evidence of a flaw in the wellhead market. The proposed rule's reliance on this difference as a basis for radical change is evidence of a flaw in the agency's analysis.

2. **The Proposed Rule Is Based on an Irrational Suspicion of Legitimate Arm's-Length Transactions.**

In 1988 the Department determined that it would continue to accept a lessee's proceeds under an arm's-length sales contract as "the best measure of market value." 53 Fed. Reg. 1186 (1988). The Department defined an arm's-length contract to mean one "arrived at in the market place between independent, nonaffiliated persons with opposing economic interests regarding that contract." 30 C.F.R. § 206.101. It placed no further restrictions on the use of arm's-length proceeds, absent a finding of unreasonable or bad faith behavior by the lessee when negotiating the contract. 30 C.F.R. § 206.102(b)(1)(ii) and (iii).

The Department's rationale for this policy was well-founded and straightforward.

> The MMS believes that the gross proceeds standard should be applied to arm's-length sales for several reasons. MMS typically accepts this value because it is well ground in the realities of the marketplace where, in most cases, the <u>7/8ths or 5/6ths owner will be striving to obtain the highest attainable price</u> for the oil production for the benefit of itself; the <u>royalty owner benefits</u> from this incentive. It also adds <u>more certainty</u> to the valuation process for payors and provides them with a clear and equitable value on which to base royalties. Under the final regulations, in most instances the lessee will not need to be concerned that several years after the production has been sold MMS will

> establish royalty value in excess of the arm's-length contract proceeds, thereby imposing a potential hardship on the lessee.

53 Fed. Reg. 1198 (1988) (emphasis added).

The proposed rule retains one small piece of common ground with the current regulations. It would continue to honor "true arm's-length sales," 62 Fed. Reg. 3744, as the best indicator of the wellhead value of oil, and would use the lessee's gross proceeds from such a sale as the proper value for royalty. Obviously, DPC supports this position. It relies on the market transaction closest to the wellhead. It recognizes that the lessee, as owner of the production, has at least as much incentive as the lessor (whose claim is only to a fraction of that production) to maximize income from the sale of the oil. And it requires the least amount of paperwork and accounting time for reporting, auditing, and enforcement.

The crucial problem with the proposed rule is that this gross proceeds approach to valuation becomes the exception, rather than the usual rule of valuation as it is under the current regulations. MMS is well aware of this, noting that it "expects that a relatively small volume of Federal oil production would be valued using the arm's-length gross proceeds method." 62 Fed. Reg. 3744. In fact, the proposed rule is so restrictive that only an extremely small volume of oil will be valued under this approach. Read literally, the three limitations in the rule which restrict the use of the gross proceeds approach assure that no oil will qualify for gross proceeds treatment. These limits concern "crude oil calls," exchange agreements, and producers who also have purchased oil within the last two years. Each of these restrictions rests on false assumptions about the oil market.

a. The Purchase of Crude Oil Is Not a Suspect Transaction.

Under the proposal, a lessee may not rely on its gross proceeds if it, or any affiliated company, "purchased crude oil from an unaffiliated third party in the United States in the 2-year period preceding the production month." Proposed § 206.102(a)(6), 62 Fed. Reg. 3753. The restriction applies without regard to the purpose of the purchase. It applies whether or not the lessee is also selling other oil to the party from whom it has bought within the two prior years.

MMS would treat lessees which purchase oil as suspicious because of the mere possibility that the parties could manipulate the contract price.

> Just as with exchange agreements ..., a producer may have less incentive to capture full market value in its sales contracts if it knows it will have reciprocal dealings where it may be able to buy oil at less than market value. Several MMS consultants reinforced the notion that as long as the two parties maintain *relative* parity in value of oil production traded, the *absolute* contract price in any particular transaction has little meaning.

62 Fed. Reg. 3743.

DPC finds little in the rulemaking record to support this assertion. Only one of the consultants (who makes a living as a plaintiffs' witness) discussed the problem of producers as purchasers. That consultant argued that some major oil companies follow an informal practice of keeping an "overall balance." That is, "as long as two companies sell approximately equal volumes to each other, the absolute price [in their various sales agreements] isn't important." But this consultant did not attempt to prove that any two major integrated companies actually have followed this practice, and he specifically disavowed that independents do so. (See Exhibit 6.) Despite MMS's reference to "several ... consultants," this is the only one to have addressed the subject.

Under the proposed rule, any lessee who has bought oil from a third party within the last two years cannot rely on its proceeds under its arm's-length contracts, because of the possibility that the lessee has engaged in an elaborate sweetheart scheme with that party. But MMS apparently despairs of ever being able to detect such a scheme, because it does not simply single out lessees who buy volumes of crude oil equal to those they sell to the same party. Instead, MMS paints with the broadest brush, banning all purchasers of oil from using the gross proceeds approach. In so doing, MMS essentially eliminates the gross proceeds approach, because producers buy oil.

We start with MMS's unproven premise: that two companies can keep track of disconnected deals with each other to assure that they can mutually undervalue oil bought and sold and still remain in economic "overall balance." More concretely, the premise is that company A can buy San Joaquin Valley heavy crude oil from company B, and sell Louisiana Light Sweet crude oil to company B in unrelated deals in different months over time, and manage to keep the volumes and the undervaluation of each oil in balance. That is a tall order. One must recognize that company A's need for San Joaquin Valley heavy oil is determined by market forces (supply of and demand for heavy crude oil in California) essentially unrelated to the market forces affecting its sale of Louisiana Light Sweet crude oil (supply of and demand for light crude oil in the Gulf of Mexico region). To make this exercise worth the trouble, the two companies would have to agree to a significant undervaluation of each crude to see a real dividend in reduced royalties and taxes outweighing the increased administrative costs of such a scheme. And a significant undervaluation is easy to detect even in the most casual of MMS audits.

Almost all lessees buy oil, and do so for reasons completely unconnected to such schemes. Many operators of federal leases "buy" oil from the co-lessees under the terms of division orders or operating agreements to authorize the operator to sell the production from the lease or unit. Examples of these agreements and orders are found as Exhibits 7 through 9.

Widely used within the industry are the model forms approved by the American Association of Professional Landmen ("AAPL"). AAPL Form 610-1977 is the

"Model Form Operating Agreement" which sets out the standard procedure for dealing with the problem of having multiple working interest owners with rights in a common stream of production from a given well. Under part VI. C. of the agreement, each working interest may take its proportionate share of the oil "in kind" and dispose of it; and every added expense from taking its share in kind is borne by that working interest alone. But any party who does not take its share in kind is subject to the right of the operator "to purchase such oil and gas or sell it to others at any time and from time to time, for the account of the non-taking party at the best price obtainable in the area...." (Exhibit 7, at 7.) The more recent AAPL Model Form Operating Agreements, Forms 610-1982 and 610-1989, continue the same procedure. (Exhibits 8 and 9.)

A similar procedure is standard in some forms for division orders. Simply because independent companies acting as operators use this standard procedure, they are thrown into MMS's alternative valuation scheme. Yet MMS has offered no evidence that their sales contracts have been the subject of manipulative dealing.

Other lessees sell their OCS oil production to a purchaser at arm's length at the lease; but they buy back 20 percent of the oil at an onshore location in order to deliver that oil to an MMS-designated small or independent refiner as required by the set-aside clause of their leases. (*See* 43 U.S.C. § 1337(b)(7).) Because the lessee has "purchased" oil, it would not qualify for use of the gross proceeds approach under the proposed rule. The only benefit to the lessee from selling the 20 percent set-aside volume at the lease and repurchasing it onshore is to transfer the risk of loss from the lessee to the first purchaser while the oil is in the offshore pipeline. MMS's royalty is not diminished in any way, and the lessee receives from the refiner nothing more than the wellhead price plus the cost of transportation.[3] An example of this kind of transaction is provided as Exhibit 10.

California lessees producing heavy crude oil often must buy light crude oil to blend so that the oil may be moved in unheated lines such as the All American Pipeline. MMS Director Quarterman has recognized this common practice in her memorandum to Assistant Secretary Armstrong on May 31, 1996, concerning the value of crude oil from the Elk Hills Naval Petroleum Reserve.

> Elk Hills oil is a higher quality crude (27-35 degrees API), which is more desirable for mixing with other crudes during transportation than the heavy crudes predominantly found in the San Joaquin Valley. This quality can avoid the need to access

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[3] The two-year restriction raises a separate concern. It is retroactive because it uses behavior occurring prior to the effective date of the rule (the purchase of oil) to alter the royalty consequences for lessees after the effective date of the rule. Even if MMS were to keep some restriction on the purchase of oil, it would be unlawful to have that restriction tied to conduct prior to the effective date of the rule.

> the few, more expensive heated pipelines available to transport heavy crude.

(See Exhibit 11.)

Finally, there is scarcely an independent producer who does not purchase crude oil for operations on the lease. For example, to improve the rate at which a given well will flow and to increase the ultimate recovery of oil from that well, a producer may fracture stimulate the producing formation. The producer must consider several concerns in selecting the fracturing fluid, but crude oil or condensate is often the best fluid to address those concerns. Oil-based fracturing fluid systems are particularly useful in treating reservoirs that exhibit sensitivity to water and that require hydraulic fracturing treatments with proppant-laden fluid to become economically producing wells.

Nothing in these transactions suggests that the lessees are engaged in manipulation of their contract prices. It would be arbitrary for MMS to prevent lessees which purchase oil from paying royalties on the gross proceeds from their arm's length sales.

b. The Restriction on Oil Subject to Crude Oil Calls Is Unfounded.

Under the proposal, a lessee may not pay royalties on its gross proceeds if the oil "is subject to crude oil calls." Proposed § 206.102(a)(4), 62 Fed. Reg. 3752. A "crude oil call" is defined to mean "the right of one person to buy, at its option, all or a part of the second person's oil production from an oil and gas property." Proposed § 206.101, 62 Fed. Reg. 3751. The definition appears to be intended to cover what others have named a "call on production," WILLIAMS & MEYERS, OIL AND GAS LAW § 427, an "option to purchase production," HEMINGWAY, LAW OF OIL AND GAS § 9.8 (3rd ed. 1991), a "preferential right and option," *Guidry v. Conoco, Inc.*, 1994 WL 518034 (E.D. La. 1994), or a "right of first refusal," *Cibro Petroleum Products v. Citgo Petroleum Corp.*, 602 F. Supp. 1520 (N.D.N.Y. 1985). The restriction is not limited to oil actually purchased by the owner of the call, but applies to oil <u>subject to</u> a call. It applies whether or not the price to be paid for the oil was negotiated at the same time the call was created.

Crude oil calls are contract based rights, ordinarily reserved by a prior owner of an oil property when conveying rights in the property to a purchaser, giving the prior owner the option of buying the crude oil produced. MMS's reason for this restriction is that the price negotiated at arm's length between the parties to the call is "suspect ... because the sale terms may be liberal to the property buyer in return for a favorable product purchase price by the property seller." 62 Fed. Reg. 3744.

The restriction on oil subject to a crude oil call is unwarranted and unworkable. At the outset, it is important to put this issue in perspective. The owner of the largest number of crude oil calls in the United States **is the United States!**[4] Everyone -- from Exxon to the smallest independent -- is subject to this call on their federal and Indian leases. Everyone is thus disqualified from using the gross proceeds approach. Yet experience indicates that the United States is motivated to maximize its income from the sale of the rights to the lease as well as from its royalty share. If this were not so, there would be no proposed rulemaking on which DPC could offer these comments.

There is similarly no reason to suspect that a privately negotiated crude oil call would leave the call owner or the callee any less eager to maximize his income. Like the United States itself, private owners of rights in oil properties often wish to reserve the option of buying the oil produced from the lease when they grant their lease rights to a third party. Exhibit 12 is from a farmout agreement. There the farmor retained a "continuing option to purchase" the farmee's oil on 30 days' notice. The farmor is required to pay the farmee "the prevailing wellhead market price then being paid in the same field for production of the same or similar grade and gravity...." Exhibit 13 is an assignment with the assignor retaining the same right to the production on 30 days' notice and on payment of "the prevailing wellhead market price...." Exhibit 14 is a sale of the property with the seller retaining the same right upon payment of the same price. *See also Industria Sicilian Asfalti v. Exxon Research and Engineering Co.*, 1977 WL 1353 (S.D.N.Y. 1977) (discussing "right of first refusal at the prevailing market price"). In these cases the farmee, assignee, and buyer are going to obtain the best price the market will allow for that production at the time the other party exercises the call.

Calls on production retained by companies which issue posted price bulletins may use the particular company's posted price as the value to be paid for production. Exhibit 15 is an example of assignment from a major integrated company to an independent. The price to be paid "shall be Assignor's posted price...." However, if the assignee receives "a bona fide offer to purchase from an independent party" which beats the posted price, then the assignor must match that offer within 10 days or else its call is "temporarily waived." Exhibits 16 and 17 are essentially the same. Again, a sale under this kind of call raises no concerns about the producer's ability to obtain a fair price for royalty purposes.

In the time permitted for comment, DPC has been unable to conduct a comprehensive survey of the range of pricing provisions in crude oil calls. But the evidence in the rulemaking record regarding crude oils calls hardly warrants the cost of undertaking

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[4] The United States has the right to buy "at the market price" every barrel of oil a lessee produces on the Outer Continental Shelf. 43 U.S.C. § 1341(b). It claims a similar right with respect to Indian mineral leases. 25 C.F.R. § 211.11 (in time of public emergency, any federal agency may purchase all oil from a lease "at the posted market price") and § 212.17 (same right to purchase "at the highest posted market price"). Under section 30 of the Mineral Leasing Act, 30 U.S.C. § 187, each onshore federal lease provides that the Secretary may buy all or part of the production from the lease.

such an effort. Furthermore, there is absolutely no reason to suspect an arm's-length sale, even if subject to a call, when the call is not exercised. The fear that Crude Oil Call Owner A may have signed a sweetheart deal with Lessee B has no bearing on B's arm's-length sale to Buyer C. One independent with whom we discussed the issue reported that of 36 wells subject to a crude oil call, only on three had the call ever been exercised. There is also no reason to question oil sold under a call if the price was not negotiated at the time the call was created. *See Guidry v. Conoco, above* (oil taken under a call at the callor's posted price "or such other price as shall be agreed between" the parties). If the price the lessee has to pay to obtain the lease rights has already been set, the lessee has no incentive to give a less than market price to the owner of the call.

Perhaps the greatest difficulty for DPC's members on the subject of crude calls is the cost of insuring compliance. Not every right of call appears in documents recorded in government title records. Some are created in documents that are merely referenced in record title documents. Some are 50 to 60 years old, far back in a chain of title comprised of multiple links of ownership. Compliance with the proposed rule would require renewed title examinations for each lease. That is an irrationally high price to pay when MMS's current rules already address the very slim risk of a manipulated sale price under a crude oil call.

c. **The Restriction on Exchange Agreements Is Ill-Considered.**

Under the proposed rule, a lessee may not pay royalties on its gross proceeds if the oil is "disposed of under an exchange agreement...." Proposed § 206.102(a)(4), 62 Fed. Reg. 3752. An exchange agreement is defined to mean any agreement "where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location." Proposed § 206.101, 62 Fed. Reg. 3751. The term includes buy/sell agreements in which a price is specified for the oil exchanged. The term is not limited to agreements in which the parties are trading an identical number of barrels. The term, however, does not include "'transportation' agreements, whose principal purpose is transportation." *Id.* MMS considers a transportation agreement to be one specifying "a location differential for moving oil from one point to the other with redelivery to the first party at the second exchange point." 62 Fed. Reg. 3744.

MMS regards exchange agreements as suspect because "the prices stated in an exchange agreement may not reflect actual value. For example, if the market value of oil were $20 per barrel (bbl), the two parties to the exchange each could price their oil at $18 bbl." *Id.*

MMS's approach to exchange agreements is difficult to justify. First, consider a simple barrel-for-barrel exchange with no price differential. Under such an exchange, neither party has set an express price, so there can be no manipulation of that price. The solution is to look at the nearest comparable wellhead transaction conducted at arm's length and apply that value to the exchange. That is the current practice, and in this context the fear of manipulation does not apply and cannot justify a change.

The fear of manipulation is only rational when the parties place a price in an arrangement like a buy/sell contract and use that price as the value of royalty. Arguably, two parties to such an exchange could agree to price oil that they otherwise would sell for $20 at only $15. But reality places significant constraints on a company's willingness to do this. For the undervaluation scheme to work for both parties, they would have to trade identical volumes of identical crude in a relatively short-term transaction. If the transaction were to last for more than, say, two months, the values of otherwise identical crudes could vary at different locations based on local shifts in supply and demand. The parties could not satisfy themselves that their relative positions would remain equal under the trade. If the crudes in the transactions were not identical, then the parties would have to have detailed information about the "real" value of each crude so that they would know by how much to underprice each crude in the buy/sell agreement. Of course, through its very impressive data base, MMS has at least equal access (and probably superior access) to the information needed, so it could spot an undervalued exchange as quickly as the parties could arrange it. Finally, the volumes would have to be identical. For if one party was buying 400 barrels and selling 500 barrels at $15/bbl, then the other party is engaged in an outright purchase of 100 barrels at $15/bbl, $5/bbl below the $20 market price. The seller presumably is sufficiently motivated not to agree to such a discount.

MMS's consultant, Summit Resources, advised the agency that buy/sells are largely a transaction favored by major oil companies, not independents. (See exhibit 5.) Our own survey of DPC members suggest that only a small percentage of their crude oil is involved in buy/sells, typically less than 25 percent. But it can be a useful transaction to market oil. It is therefore not reasonable for MMS to disregard all oil valued under exchange agreements (as that term is broadly defined); and in all events MMS has failed to justify why it cannot simply continue to compare the values used in exchanges with comparable arm's-length sales to set the proper value. In what fields have companies valued oil under buy/sells at prices significantly different than those obtained in comparable outright sales? The rulemaking record provides no answer.

Furthermore, there is often no real distinction between a buy/sell agreement (which is treated as an exchange agreement) and a transportation agreement (which is not). In California, in particular, companies owning proprietary pipelines sometimes require the independent producer to enter a transportation agreement which looks exactly like what MMS's proposal calls a buy/sell. They do so because they believe that structuring the deal in that way is more persuasive evidence that they are truly moving their own production. Obviously, what the producer first gets from the pipeline is all the revenue it gets from the wellhead transaction.